Permit Review
Chapter 127

To: Mark J. Wejkszner
Program Manager

Through: Raymond Kempa
Chief, New Source Review Section

From: Brian Halchak
APCE III

Date: March 4, 2009

Region 2	Luzerne County
Permit Number	40-328-006
Company Name	UGI Development Company Hunlock Power Station
Source Description	Two (2) GE LM6000 combined-cycle combustion turbines, two (2) HRSG, one (1) auxiliary boiler 500,000 gallon storage tank, 10,000 gallon storage tank
Control Equipment	Selective Catalytic Reduction, CO Catalyst
Location of Sources	Hunlock Township, Luzerne County

THE COMPANY HAS SUBMITTED THE FOLLOWING DOCUMENTATION AS REQUIRED FOR THE PLAN APPROVAL TO BE COMPLETE:

a. A completed Air Pollution Control Act Compliance Review Form dated June 11, 2008.
b. Municipal notification received by the host municipality on June 24, 2008 as required by Act 14.
c. Municipal notification received by the host county on June, 24, 2008 as required by Act 14.
d. A check in the amount of $5,100 consistent with Subchapter I of Chapter 127 of the Rules and Regulations of the Department of Environmental Protection.
e. The General Information Form was submitted as part of the application on June 11, 2008.

THE DEPARTMENT HAS TAKEN THE FOLLOWING ADMINISTRATIVE ACTIONS:

a. The Application Acceptance/Administrative Completeness Letter was sent on July 3, 2008.
b. Coordination with other agencies was done and is not required.
c. Notification in the Pennsylvania Bulletin on July 19,2008 to allow an additional 30-day comment period for the public to respond. No comments have been received from the public or other agencies.
d. Additional technical information required letter dated August 27, 2008
e. Received additional information requested from UGI development Hunlock Station February 2, 2009.

GENERAL INFORMATION:

UGID is proposing to construct and operate a combined-cycle power plant at the Hunlock site located about 10 miles south of Wilkes-Barre, Pennsylvania in a rural setting in Hunlock Township, Luzerne

County. The facility is arranged on an approximately 60-acre parcel of land next to the west bank of the Susquehanna River's North Branch. The project will replace the existing Unit 3 coal-fired boiler (the "Project"). The coal-fired boiler will be retired in place. The new combined-cycle plant will consist of:

Major equipment associated with the Project includes:

- Two GE LM6000 PC-Sprint CTGs (designated as Units 5 and 6).
- Two (2) supplementary natural gas-fired HRSGs with separate exhaust stacks (one for each Combustion Turbine ("CT")
- Use of existing STG (steam turbine generator)
- Nominal 500,000-gallon capacity low sulfur distillate storage tank
- A natural gas-fired package boiler (< 50MMBtu/hr) to provide heat to the existing administration building and related plant facilities
- Nominal 10,000-gallon capacity aqueous ammonia storage tank
- Demineralized water storage tank, nominally 150,000-gallon capacity

Each Combustion Turbine ("CT") will be arranged with a Heat Recovery Steam Generator ("HRSG") that will generate steam using the heated exhaust from its associated CT, thus operating in combined-cycle mode. The CTs will burn natural gas as the primary fuel and low-sulfur distillate as an alternative fuel (approximately one month each year).

The steam from each HRSG will be fed to the existing (albeit refurbished) Unit 3 condensing STG to generate additional power. The HRSGs will have supplemental duct-firing capability (utilizing only natural gas) to increase steam and, therefore, power output primarily during periods of peak demand. The proposed state-of-the-art combined-cycle electric generating facility designed to generate approximately 122 MW (net, average annual) of electricity. Two GE LM6000 PC-Sprint combustion turbines are proposed as the prime mover for the Project.

PROCESS DISCRIPTION:

The Project will use combined-cycle power generation technology to maximize generation efficiency and minimize fuel usage. This technology is nearly 30% more efficient than vintage steam-electric utility power plants. Since combined-cycle units burn less fossil fuel to generate an equivalent amount of power, they also emit substantially less air pollutants, including greenhouse gases such as carbon dioxide ("CO_2"). The Project primary fuel will be pipeline natural gas. Low sulfur (0.05% wt. S) distillate will be used as a secondary fuel. The combustion turbine will use water injection to minimize the formation of nitrogen oxides ("NO_x") during the combustion process.

In a combined-cycle facility, fuel is fired in a CT. The expanding exhaust gas turns a rotor that is attached to dedicated electric generators (i.e., the generator portion of the CTG) and thereby producing electricity. The hot exhaust gas leaving the CTs is then used to convert water to steam in each HRSG. For this project, the HRSGs will include natural gas-fired duct burners to increase the CT exhaust gas temperature and plant capacity

Combustion Turbines

The CT is the core component of a combined-cycle power system. For this project, two GE LM6000 PC Sprint CTs are proposed. Each CT will be connected to a dedicated electric generator that will produce nominally 50 MW each.

First, air is filtered and compressed in a multi-stage axial-flow compressor. Compressed air and fuel are mixed and combusted in the CT chamber. Exhaust gas from the combustion chamber is then expanded through a multi-stage power turbine that drives both the inlet air compressor and an electric power generator. The combustion chamber is equipped with a water injection system to minimize NO_x formation during combustion. Highly purified water is injected into the combustion chamber prior to combustion lowering the peak flame temperatures and thus reducing the formation of thermal NO_x.

Heat Recovery Steam Generators

The Project design includes two supplementary-fired HRSGs. In a combined-cycle facility, a HRSG extracts heat from the CT exhaust gases to produce steam that is used to drive a STG. The HRSGs will include a two-pressure steam system and the proposed emission control systems. The proposed emission control systems are carbon monoxide ("CO") oxidation catalyst and selective catalytic reduction ("SCR") systems. The heat extraction process will cool the flue gases that enter the HRSGs at approximately 850°F to approximately 200°F prior to release through the HRSG stacks. Separate nominal 192-foot tall exhaust stacks are proposed.

The HRSG duct burners will be natural gas-fired only with a rated capacity of 38.9 MMBtu/hr. Operations of the HRSG duct burners will be limited to 77.8 MMscf/yr per unit which is equivalent to 2,000 hrs/yr.

Steam Turbine

The Project will use the existing Boiler #6 STG associated with Unit 3. Steam produced in the HRSGs will be expanded in the STG to drive a dedicated generator that will produce electricity. The STG has a nominal rating of 50 MW.

Fuel Systems

Natural gas will be the CT's primary fuel and will be the sole fuel for the HRSG duct burners and steam boiler. The natural gas used by the facility will vary according to pipeline supply conditions. For purposes of emission calculations, the natural gas is assumed to have a nominal higher heating value ("HHV") of 1,000 Btu/scf and a maximum sulfur content of 0.8 grains per 100 scf.

Low sulfur (0.05% wt. S) distillate fuel oil will be used as the secondary fuel by the CTs. A new nominal 500,000-gallon capacity low sulfur distillate fuel oil tank will be installed. Low sulfur distillate usage will be limited to 1,955.5 Kgal/yr per unit, which is equivalent to 600 hrs at 100% load.

CONTROL EQUIPMENT:

Combustion Turbine Emissions Control Techniques

The Project will include air pollution control equipment to comply with State BAT requirements as applicable, for each significant air pollutant. The control technologies to be employed are summarized below.

Nitrogen Oxides – The Project will control NO_x emissions by means of water injection in conjunction with SCR.

Carbon Monoxide – CO emissions will be controlled by a oxidation catalyst and good combustion practices.

Sulfur Dioxide ("SO_2") – SO_2 and other sulfur emissions such as sulfuric acid ("H_2SO_4") mist will be minimized by the use of pipeline quality natural gas and low sulfur (0.05% wt. S) distillate.

Particulate Matter ("PM") – Particulate emissions will be minimized by the use of pipeline quality natural gas, low sulfur (0.05% wt. S) distillate, and efficient combustion.

Volatile Organic Compounds ("VOC") – VOC emissions will be controlled by good combustion practices. While it is expected that the oxidation catalyst will provide up to approximately 40% control of VOC, this reduction level is not guaranteed by the catalyst vendors and has not been accounted for in the emission estimates.

Hazardous Air Pollutants ("HAP") – HAP emission will be controlled by a combination of the use of pipeline quality natural gas, low sulfur (0.05% wt. S) distillate, good combustion practices, and the use of an oxidation catalyst. HAPS consisting of heavy metals will be minimized by the use of natural gas low sulfur (0.05% wt. S) distillate, and good combustion practices. Organic HAPS, such as formaldehyde, which are mostly the result of incomplete combustion will be minimized by the oxidation catalyst and efficient combustion.

OTHER SOURCES:

Ammonia Storage

Aqueous ammonia injection will be used to facilitate NO_x control in the SCR system.. The Project specification is for 19% aqueous ammonia. The ammonia will be stored in a nominal 10,000 gallon aqueous ammonia tank on the Project property.

Steam Boiler

A natural gas-fired boiler (utilizing less than 50 MMBtu/hr, nominal) is proposed to provide heat to the existing administration building and related plant facilities building. This unit will replace two existing 20,000 lb/hr oil-fired auxiliary boilers. Note that emission reductions from these existing units are not included in the PSD and NNSR netting analyses.

Project Emissions

The emission calculation methodologies used rely on manufacturer's data, expected control technology efficiencies, fuel specifications, and standard emission factors from USEPA AP-42. Unit design parameters and operational practices and limitations have been incorporated into the analyses to make the emissions estimates realistic and representative of onsite conditions.

GE provided UGID with estimated operational data for normal operating conditions for the combustion turbine, including pollutant concentration levels, turbine heat input and combustion turbine exhaust gas analysis from full load to 50% of full load. This load range is defined as the normal operating range of the unit. Final pollutant concentrations and mass emission rates were developed by UGID for this operating range based on the vendor supplied combustion turbine emissions data, proposed emission control systems, fuel specifications, and standard emission factors. Pound per hour mass emission rates as provided by GE are based on new and clean equipment. The Project has added a 10% margin to the vendor supplied mass emission rates to account for variations in ambient conditions and equipment degradation over time.

- NO_x emissions are based on controlled, in-stack pollutant concentrations of 3.5 ppmvd at 15% O_2 (natural gas normal operations), 4.0 ppmvd at 15% O_2 (natural gas normal operations, with duct-firing), 9.0 ppmvd at 15% O_2 (low sulfur distillate), and 9.5 ppmvd at 15% O_2 (low sulfur distillate, with duct-firing). In-stack NO_x concentration levels will be guaranteed over the range of normal operating conditions.

- CO emissions are based on controlled, in-stack pollutant concentrations of 20.0 ppmvd at 15% O_2 (natural gas normal operations with and without duct-firing) and 5.0 ppmvd at 15% O_2 (low sulfur distillate normal operations, with and without duct-firing). In-stack concentration levels will be guaranteed over the range of normal operating conditions.

- VOC emissions are based on in-stack pollutant concentrations of 4.0 ppmvd @ 15% O_2 (natural gas normal operations with and without duct-firing) and 8.0 ppmvd at 15% O_2 (low sulfur distillate normal operations, with and without duct-firing). In-stack concentration levels will be guaranteed over the range of normal operating conditions.

- SO_2 emission rates are based on vendor provided fuel consumption rates, a worst-case fuel sulfur content and nominal fuel Btu content. All fuel sulfur is assumed to be emitted as SO_2.

- H_2SO_4 emissions were estimated based on the SO_2 emission rate, an assumption that up to 30% of the SO_2 will oxidize to SO_3 across the oxidation catalyst, and that all the SO_3 will combine with water vapor in the stack to form H_2SO_4. Note that the SO_2 emission rate does not take any credit for this conversion of SO_2 to H_2SO_4; therefore, the SO_2 and H_2SO_4 emission rates double-count a portion of the fuel sulfur.

- PM_{10} emission rate is based on vendor supplied non-condensable particulate matter (PM) emission rate and an estimate of condensable particulates. To estimate condensable PM_{10} emissions, it is conservatively assumed that all SO_3 combines with NH_3 to form ammonium sulfates. This effectively triple-counts the SO_3 as SO_2, H_2SO_4, and condensable particles. $PM_{2.5}$ emissions are assumed to equal PM_{10}.

- Hazardous air pollutant (HAP) emissions were estimated using emission factors from AP-42.

- Additional emissions from duct firing are based on vendor estimated emission factors and the assumed SCR and CO catalyst control efficiencies.

Whenever the Plant is dispatched, UGID expects to operate the combustion turbines at or near the 100% (Base) load case for the majority of the time. However, to provide operational flexibility, UGID has evaluated emissions over a potential range of normal turbine operating modes. Excess emissions attributable to combution turbine startup and shutdown were also evaluated based on vendor supplied data.

For the LM6000 turbine, UGID proposes a normal operating range of between approximately 50 and 100% load for both the primary and secondary fuels. In addition to operating load, combustion turbine emissions vary with ambient temperature. UGID evaluated combustion turbine operating parameteres at five ambient temperatures, -10°F, 25°F, 50°F, 75°F, and 85°F.

The combustion turbine will also have the capability of using inlet chilling to cool the inlet air to increase power generation at ambient temperatures above 50°F. Inlet chilling will use an absorption chiller, with low pressure motive steam from the steam turbine cycle, to generate chilled 45°F water. The chilled water will pass through heat exchanger coils at the inlet of the turbine, cooling the incoming air to approximately 50°F. Note that this operating mode was not individually investigated. While performance with inlet chilling will impact stack gas exit parameters, the effected parameters are within the range of conditions investigated

The maximum worst-case short-term emission rates for the LM6000 combined cycle combustion turbine system is presented in the table below.

Combustion Turbine Fuel	*Natural Gas*	*Natural Gas*	*Low Sulfur Distillate*	*Low Sulfur Distillate*
Duct Burner	No	Yes	No	Yes
Pollutant	Maximum Hourly Emission Rate (lbs/hr)			
NO_x	6.6	7.7	19.5	17.2
CO	21.8	23.5	2.5	2.3
SO_2	1.1	1.2	23.0	23.1
PM_{10}	5.1	5.6	30.8	31.2
VOC	2.6	2.7	5.3	5.7
H_2SO_4	0.49	0.54	10.5	10.6
NH_3	6.9	7.1	7.1	7.6

STARTUP/ SHUTDOWN

As stated, the Project has defined the normal operating range for the LM6000 combustion turbine as between 50 to 100% load. During normal operation, the turbines will meet the emission limitations as defined by control technology review. During periods of startup, shutdown, or malfunction, combustion turbine emissions of certain pollutants will be elevated until the combustion turbine and emission control systems reach steady-state operation.

Pollutants most likely to be effected are CO, NO_x and VOC. SO_2 emissions are strictly a function of fuel usage and therefore are not elevated during startup or shutdown. No data exists for particulate emissions during startup, however, since a significant portion of the PM_{10} emissions are condensable particulates, mostly ammonium sulfates. PM_{10} emissions are not expected to be elevated above permitted levels during startup or shutdown.

Startup and shutdown emission estimates for typical operations under ISO conditions were provided by GE. Based on the data provided by GE:

- A typical startup, defined as from initial fuel firing to combustion turbine steady state operation, is expected to take approximately 1 hour.
- A typical shutdown, defined as from when steady state combustion turbine operating load falls below normal operations to cessation of fuel firing, is expected to take approximately 30 minutes.

- Peak CO and NO_x concentrations are expected to average less than 100 ppmvd @ 15% O_2 over the startup/shutdown period.
- During the startup/shutdown period, actual emissions will be greater than steady-state controlled emissions.
- The avoided emissions that would have occurred had the unit not undergone a startup/shutdown sequence and been operating at normal base load conditions are greater than the elevated startup/shutdown emissions. Therefore, annual tpy emissions are "self-correcting".

The following table represents the total emissions for the facility

	Annual Pollutant Emissions (tpy)						
	NO_x	CO	VOC	SO_2	PM_{10}	H_2SO_4	NH_3
Combustion Turbines	44.9	30.1	9.30	25.5	72.5	8.70	27.7
Steam Boiler	1.8	4.2	0.3	0.1	0.4	Neg	0.0
Storage Tank	0.0	0.0	0.008	0.0	0.0	0.0	0.0
Project Total	46.8	34.3	9.68	25.6	72.9	8.70	27.7

Nonattainment Area NSR Applicability:

25 Pa. Code Chapter 127, Subchapter E contains requirements for sources located in a non-attainment area. Emissions of ozone precursors VOC and NOx are potentially subject to non-attainment NSR ("NNSR"). Luzerne County is designated as an attainment area for PM2.5 therefore NNSR applicability is not required. The applicability threshold for NNSR is: VOC 50 tpy, NOx 100 tpy. NSR Applicability is two steps program:

Step 1: Calculation of the emissions increases of each regulated NSR pollutant due to the project
Step 2: Net Emissions Increase Calculation

Step 1:
The term "project" is defined at 25 Pa. Code Section 121.1 as a physical change in or change in the method of operation of an existing facility, including a new emissions unit. Therefore, a project includes new emissions units, modifications to existing emissions units, replacement units and de-bottlenecked units.

Major equipment associated with the Project includes:

- Two GE LM6000 PC-Sprint CTGs (designated as Units 5 and 6).
- Two (2) supplementary natural gas-fired HRSGs with separate exhaust stacks (one for each Combustion Turbine ("CT")
- Use of existing STG (steam turbine generator)
- Nominal 500,000-gallon capacity low sulfur distillate storage tank
- A natural gas-fired package boiler (< 50MMBtu/hr) to provide heat to the existing administration building and related plant facilities
- Nominal 10,000-gallon capacity aqueous ammonia storage tank

- Demineralized water storage tank, nominally 150,000-gallon capacity

The following table represents the total emissions for NSR regulated pollutant due to the project:

Emissions Units		***Method for determining emissions increase***	*NO_x*	*VOC*
Combustion Turbines	New Emissions Unit	Potential to Emit	44.9	9.3
Steam Boiler	New Emissions Unit	Potential to Emit	1.8	0.3
Storage Tank	New Emissions Unit	Potential to Emit	0.0	0.008
Project Total	New Emissions Unit	Potential to Emit	46.8	9.608

Step 2: Net Emissions Increase Calculation

Since NOx emissions increase due to the project exceeds the listed applicable rate; we will use provisions of §127.203a(a)(1)(ii) to calculate net emissions increase.

§127.203a(a)(1)(ii): <u>(Similar to Federal NSR)</u>

Net Emissions increase =
<u>Plus</u> Increase in emissions due to the project (44.9 tpy of NOx)

<u>Plus</u> Other increases in actual emissions occurring within the 5-year period. (0 tpy)

<u>Minus</u> Other decreases in actual emissions occurring within the 5-year period. (526 tpy)

= -479.2 tpy of NOx

Since VOC emissions due to the project does not exceed the the listed applicable rate; we will use provisions of §127.203a(a)(2) to calculate net emissions increase. ("De minimis emissions increase calculation")\

§127.203a(a)(2): <u>(De minimis emissions increase calculation)</u>

Net Emissions increase =
<u>Plus</u>Proposed de minimis emissions increase due to the project (9.6 tpy)

<u>Plus</u> Other previously determined increases that occurred within 10 years prior to the date of a complete plan approval application. (please provide)

<u>Minus</u> Other decreases in actual emissions that occurred within 10 years prior to the date of a complete plan approval application. (- 5.3 tpy)

= 4.1 tpy of VOCs

Since the *net emissions increase* is below the 40 tpy of NOx and VOCs NSR triggering threshold, the proposed project is not subject to the NNSR regulations. Thus, the proposed project has netted out of NSR.

Prevention of Significant Deterioration

Prevention of Significant Deterioration ("PSD") review (40 CFR 52.21) is a federally mandated program that applies to new major sources of regulated pollutants and major modifications to existing sources. PSD review is a pollutant-specific review that applies only to those pollutants for which a project is considered major and the project area is designated as attainment or unclassified.

Since the existing facility is a major source per the PSD regulations, PSD review would apply if the proposed project is a major modification. To make this determination, a PSD applicability analysis was conducted to determine if the Project would result in a significant net increase of any regulated pollutant. This analysis took into account emission increases attributable to the installation of new equipment, specifically the combustion turbines/duct burners, auxiliary steam boiler, and the low sulfur distillate storage tank and emission decreases associated with the shutdown of Unit #6, the existing coal-fired boiler.

Unit #6 will continue to operate for a period of time while the combustion turbines are being installed. Since the existing Unit #6 steam turbine will be used by the Project, Unit #6 will need to shutdown prior to startup of the Project to allow for the completion of the necessary connections between the HRSGs and the steam turbine. Once Unit #6 is shutdown, UGID has filed the appropriate Emission Reduction Credit (ERC) forms for the Boiler #6 and the netting analysis and ERC have been incorporated into the plan approval.

The Project will also include the installation of a new <50 MMBtu/hr natural gas-fired steam boiler. This unit will replace two existing 20,000 lb/hr oil-fired boilers. Emission increases associated with the new natural gas-fired unit are included in the netting calculation. However, as the exact timing of the installation of this new unit and shutdown of the existing units is unknown in relationship to the startup of the combustion turbines, emission reductions associated with the shutdown of the existing auxiliary boilers are not included. UGID will file the appropriate ERC forms at the time these units are shutdown.

The following table shows the netting analysis for the shut down of Boiler #6 and the new project emissions:

SPECIAL CONDITIONS:

The following table are the BAT limits imposed on the facility for the combustion turbines

Pollutant	*Control Level*	*Control Technology*	*Emission Limitation*
NO_x	State BAT	• Water Injection • Selective Catalytic Reduction	• 2.5 ppmvd at 15% O_2 – Natural gas, normal operation • 2.9 ppmvd at 15% O_2 – Natural gas, with duct-firing, normal operation • 8.0 ppmvd at 15% O_2 – low sulfur distillate, normal operation • 8.5 ppmvd at 15% O_2 – low sulfur distillate with duct-firing, normal operation
CO	State BAT	• Oxidation Catalyst • Good Combustion Practices	• 4.0 ppmvd at 15% O_2 – Natural gas, normal operation • 10.0 ppmvd at 15% O_2 -Natural gas, normal operation. Temperature <32 Degree F • 6.0 ppmvd at 15% O_2 – low sulfur distillate, normal operation
VOC	State BAT	• Good Combustion Practices • Oxidation Catalyst	• 1.20 ppmvd at 15% O_2 – Natural gas, normal operation • 4.0 ppmvd at 15% O_2 -Natural gas, normal operation. Temperature <32 Degree F • 1.30 ppmvd at 15% O_2 – low sulfur distillate, normal operation
PM10	State BAT	• Good Combustion Practices • Clean Fuels	• 0.0141lb/MMBTU at 15% O_2 – Natural gas, normal operation • 0.066 lb/MMBTU at 15% O_2 – low sulfur distillate, normal operation
SO2	State BAT	• Good Combustion Practices • Clean Fuels	• 0.0030 lb/MMBTU at 15% O_2 – Natural gas, normal operation • 0.0510 lb/MMBTU at 15% O_2 – low sulfur distillate, normal operation
H2SO4	State BAT	• Good Combustion Practices • Clean Fuels	• 0.0009 lb/MMBTU at 15% O_2 – Natural gas, normal operation • 0.0200 lb/MMBTU at 15% O_2 – low sulfur distillate, normal operation

RECOMMENDATION:

Based on the review of the plan approval application and all the supplemental information supplied to the Department by the company. The proposed project appears to comply with the requirements of State

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

PLAN APPROVAL

Issue Date: Effective Date:

Expiration Date:

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In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to construct, install, modify or reactivate the air emission source(s) more fully described in the site inventory list. This Facility is subject to all terms and conditions specified in this plan approval. Nothing in this plan approval relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each plan approval condition is set forth in brackets. All terms and conditions in this permit are federally enforceable unless otherwise designated as "State-Only" requirements.

Plan Approval No. 40-328-006

Federal Tax Id - Plant Code: 23-3061284-1 23-1650159 Correct TAX ID

Plan Approval Description

This plan approval is for the construction of an electric generating plant with a nominal output of 122 megawatts, and includes the following major equipment:

a. Two GE LM 6000 PC-Sprint combustion turbines 50MW
b. Two supplementary fired HRSG
c. Two selective catalytic reduction (SCR) systems for nitrogen oxides (NOx) control
d. Two CO Oxidation Catalyst
e. One (Existing) steam turbine 27MW

Upon start-up of the new ~~equipment~~ emission unit the facility will simultaneously shut down Boiler #6 (coal fired)

Owner Information

Name: UGI DEV CO
Mailing Address: PO BOX 224
390 ROUTE 11
HUNLOCK CREEK, PA 18621

Plant Information

Plant: UGI DEVELOPMENT CO/HUNLOCK CREEK
Location: 40 Luzerne County 40943 Hunlock Township
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: DAVID R STETTLER
Title: MANAGER - POWER PRODUCTIO
Phone: (570) 830 - 1270

Plan Approval Contact Person

Name: JEFF STEEBER
Title: ENGINEER
Phone: (570) 830 - 1270

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PM10	State BAT	• Good Combustion Practices • Clean Fuels	• 0.0141lb/MMBTU at 15% O_2 – Natural gas, normal operation • 0.066 lb/MMBTU at 15% O_2 – low sulfur distillate, normal operation
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[illegible]

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[Signature] ______________________________
MARK J WEJKSZNER, NORTHEAST REGION AIR PROGRAM MANAGER